Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls

Consultation by Ofgem

Response by E.ON

Summary of key points

- Although the Electricity Act states the capacity assessment should cover a period four years ahead, we are concerned that limiting the time horizon to this extent will not provide adequate insight or accuracy when informing decisions on necessary levels of capacity.
- We are pleased that Ofgem intends to present alternative scenarios around a base case. Given the level of uncertainty and number of variables in the model, it may be necessary to consider more scenarios than Ofgem anticipates.
- System flexibility is an important consideration that should not be ignored by the model. The capacity assessment's risk measures should be stress tested based on different assumptions of system flexibility.
- When modelling wind capacity we believe the model's assumptions should consider both correlations of wind speed with wind generation availability and technical specifications of different technologies.
- Temperature and weather trends are key assumptions that must be included and stress tested in the model. These assumptions will affect both the demand side and supply side.
- We support the intention to delegate the construction and updating of the model to National Grid Electricity Transmission plc. However, Ofgem must continue to offer independent oversight and challenge to the assumptions and stress tests going forward to ensure the assessment's integrity.

Answers to specific questions

Question 1: Do you agree that the de-rated capacity margin is a good indicator of future capacity adequacy?

1. Yes. In an increasingly diverse energy system, taking account of the various characteristics of different generation technologies will be crucial. Using a simple assessment of total capacity margin would become less reliable over time as intermittent generation becomes more widespread.

Question 2: Are there any measures of risk other than LOLE and EEU that we should report and what are their comparative advantages?

2. We agree that LOLE and EEU are appropriate measures of risk.

3. The approach proposed will not take into account the different flexibility characteristics of plants to arrive at the de-rated capacity margin and measures of risk. We agree that DECC's proposed capacity mechanism should reward all plant providing capacity (it should not differentiate between plant offering different levels of flexibility as the energy market will provide appropriate incentives for this). However, when making an assessment of risks to capacity margin, plant flexibility is an important consideration that should not be ignored.

4. We suggest that Ofgem's proposed measures of risk (LOLE and EEU) are stress tested based on different scenarios of system flexibility.

Question 3: Are there any additional key input assumptions that we should consider in the modelling?

5. Given the current and expected future levels of installed gas generation capacity we agree that the report should include a specific stress test on the availability of gas.

6. We also believe this stress test should consider the flexibility of gas supply. Increased levels of intermittent electricity generation capacity will increase the need for flexible electricity capacity. This, in turn, increases the need for flexible gas supply. Flexibility of gas supply could have significant implications for the load factors and flexibility assumed for gas-fired electricity generation capacity.

7. DECC's Renewable Energy Roadmap suggests biomass electricity generation could contribute up to 6GW capacity by 2020. Given the potential competition for biomass fuels we would suggest including a stress test covering availability of biomass fuel supplies.

Question 4: Do you agree that the use of stochastics (probability distributions) to model short-term variation of key input variables is the best available method? Do you agree with the use of scenarios and stress tests for capturing long term uncertainty in key input variables?

8. We agree with both of these approaches.

9. Stress tests will be of crucial importance in the modelling. Whilst we agree that National Grid Electricity Transmission plc will be best placed to carry out the modelling, which will ensure consistency with existing reports, there may be situations where NGET's assumptions and approaches do not adequately reflect the full range of risk in a forecast. Stress testing model results against independently generated scenarios will be necessary.

10. Given the level of uncertainty and number of variables in the model, it may be necessary to consider more scenarios and stress tests than Ofgem anticipates.

Question 5: Do you agree with the proposed approach to modelling wind availability?

11. We agree with Ofgem's view that wind technology has developed significantly in recent years and that historic correlation of wind speeds and wind generation availability alone may not be a valid predictor of future wind output. However, historic correlation should not be ignored.

12. The model should use a combination of the approaches Ofgem suggests. Technical specifications could be used as a basis for the conversion of wind speeds to wind generation availability but historic correlations for particular technologies, perhaps over a rolling period, should also be used to test and improve these assumptions over time.

13. The model should distinguish between different wind technologies (for example by turbine design) rather than using a one size fits all approach.

14. New techniques and technologies may result in improvements in wind forecasting abilities in future. Modelling assumptions should be continually assessed and updated to take account of these improvements.

15. As well as distinguishing between wind technologies, it is important to consider on- and off-shore wind separately in the model as wind conditions are likely to differ. Correlations between on- and off-shore wind can then be assessed and stress tested.

16. Embedded wind should be considered alongside on-shore wind, although there may be value in assessing embedded wind separately as it is more likely to be developed in built up areas, where wind conditions may be different.

Question 6: Do you agree with the proposed use of NGET's existing data and assumptions, regarding, in particular, commissioning and decommissioning dates and embedded generation?

17. We agree that NGET's existing data and assumptions should be used as a scenario in the model. However, past experience has shown that NGET's assumptions can be inaccurate. We would suggest that additional scenarios with different assumptions are developed alongside NGET's assumptions.

18. Developing realistic closure and new build scenarios will require some consideration of the likely economic performance of various plant types.

Question 7: Do you believe that Ofgem should require industry stakeholders to submit up-to-date data with regard to commissioning and decommissioning dates and embedded generation? Which industry process will ensure the confidentiality of information provided?

19. We agree that, in principle, confidential information from industry stakeholders could improve assumptions in the modelling. However, we do not believe such data is likely to be as useful as it would initially appear, as generators may over or under estimate their new build or decommissioning timescales.

20. Final decisions on closures may be taken by stakeholders on relatively short timescales. Therefore, commercially sensitive data submitted by stakeholders is likely to state that plant is not scheduled to close, even if closure is being seriously considered.

21. The economic performance of existing plant approaching closure is partially determined by the presence and activity of other plant (new and existing) and therefore by decisions taken by competitors that cannot be known in advance. Accordingly, decisions on plant closures or significant changes (such as biomass conversion) may be far more reactive and unpredictable than decisions on new build, particularly where new build is supported by more predictable mechanisms such as CfDs or, to an extent, the capacity mechanism. It is important that the modelling accounts for these differences and recognises the increased levels of uncertainty when considering plant decommissioning.

22. Ofgem's suggested approach of using NGET's assumptions with reduced TEC register values for older plants as a base scenario, with alternative scenarios testing sensitivity to changes in dates, is likely to be more useful than unreliable stakeholder submissions.

Question 8: What are your views on how best to model LCPD opt-out plants' restricted running regimes?

23. The draft requirements under the Electricity Act state that a report should be produced for each of the four calendar years immediately following the year of the report. We would suggest that modelling of LCPD opt out plants' restricted running regimes, along with other implications for large combustion plants operating within the Industrial Emissions Directive (IED), should be carried out over a longer time period (i.e. to 2023) to fully assess and understand the implications of these policies. A plant operator's assumptions about future levels of return (beyond a four year time horizon) will affect its decisions within the model's timeframe.

24. The various transition options available under the IED also need to be considered in the modelling.

25. We would suggest including a consideration of opportunity cost when modelling opt-out plant's restricted running regimes. This will allow the model to mirror a plant operator's decision making process.

Question 9: Which of the two approaches for modelling electricity interconnection flows will provide the most realistic flows? If you favour the scenario based approach, what are your views on reasonable scenarios to run?

26. A specific model for interconnection flows based on prices would, in theory, be the most accurate method of predicting interconnection flows. However, such a model would be incredibly complex as it would need to consider the interactions between all connected EU energy markets. We do not believe it would be possible to create such a model with a sufficient degree of accuracy.

27. Therefore, the scenario based approach appears to be the most sensible option. We believe a single base-case scenario would be unhelpful given the difficulty in predicting interconnection flows into the future; a series of scenarios, with no single base-case, would be more appropriate.

28. Scenarios will need to consider market conditions and developments in Europe and would need to include variations in supply (such as IED closures, nuclear closures, new build assumptions and renewables targets and progress towards these) and variations in demand (such as levels of industrial production, energy efficiency and regional temperature differences). These scenarios should also consider how progress towards a single European electricity market may affect price differentials between markets and the resulting impact on interconnector flows.

Question 10: Under what conditions would users respond by curtailing their demand and how would you go about modelling this? Is it worth Ofgem requesting data from DNOs on self-interruption and interruptible contracts?

29. Demand side response (DSR), both shifting and reducing demand, is likely to be a key factor in a future energy system and will significantly impact capacity margins.

30. As Ofgem rightly observes, forecasting uptake of DSR is difficult. At this stage, information from DNOs on self-interruption and interruptible contracts may help, but the real difficulty occurs when predicting mass uptake of DSR in the domestic market.

31. Predictions of DSR rely heavily on advances in technology, both in terms of advances in current technologies (for example smart household appliances) and new technologies and sources of DSR (such as electric vehicles or heating). We would suggest Ofgem consults with

technology manufacturers, energy suppliers and customers on this issue specifically to develop scenarios to use in their modelling.

32. Given the unpredictable nature of DSR volumes, it will be important to include multiple scenarios for DSR within the model.

Question 11: Is historical data of scheduled outages a good indicator of future patterns of scheduled maintenance timings?

33. The wholesale electricity market is likely to change significantly as Electricity Market Reform (EMR) proposals take effect and low carbon generation increases. Therefore, historical data of scheduled outages is unlikely to be a good indicator of future maintenance timings.

34. As new generation technologies are installed (for example new nuclear reactor designs), historic maintenance schedules may not be appropriate.

35. Scheduled outages are likely to be correlated to some extent to wholesale market prices over various time horizons; whilst we recognise the complexities involved, we would suggest Ofgem considers this relationship in its modelling of scheduled maintenance. Historic correlations of maintenance schedules with market price could be used to assess future impacts based on price assumptions.

Question 12: Will treating half-hour periods independently have significant effects on our estimates of the de-rated capacity margin and risk of supply shortfalls and how should the model take into account half-hourly cross-correlations?

36. Modelling half-hour periods independently, while simple, may lead to inaccuracies in the capacity assessment. As Ofgem rightly points out, there are a number of circumstances where half-hourly correlations could be very important, for example where periods of high or low wind output are likely to be followed by similar periods of high or low output.

37. These correlations could have a significant impact on the capacity assessment, particularly when considering the flexibility of the system and its ability to ramp up (or down) with periods of fluctuating intermittent capacity or demand (see earlier comments on flexibility scenarios). The model should take account of these correlations.

Question 13: Are there any boundaries other than Cheviot that may significantly affect the risk of supply shortfalls?

38. National Grid and other transmission companies are best placed to understand when and where constraints are likely to affect the risk of supply shortfalls.

39. The constraints on the Cheviot boundary are well documented. However, we understand that the Thames Estuary is a potential problem area and that the South West of England could become constrained if replacement generation for Hinckley Point B takes a significant time to commission.

Further comments on proposals

Time horizon

40. We recognise that Ofgem is not consulting on the time horizon for the capacity assessment. However, we are concerned that limiting the model to forecast four calendar years ahead will not provide adequate insight when informing decisions on levels of capacity.

41. Such a restriction may also limit the accuracy of the model when considering assumptions that go beyond this timeframe (see response to question 8 above). We would urge Ofgem to extend its modelling beyond this four year timeframe.

Temperature

42. When modelling demand profiles and growth, the impact of weather and seasonality must be considered and capacity assessments stress tested for these. Global warming trends should also be recognised – we would be interested to understand how Ofgem intends to account for these trends.

43. Whilst historical data could provide a good base scenario it is important to consider potential changes in demand profile in response to temperature. For example, as energy efficiency technologies develop we would expect to see differences in consumers' responses to temperature change.

44. Temperature will also be an important consideration when modelling generation capacity. For example, a gas power station will have a larger potential capacity in winter than in summer. This correlation should be captured by the model and linked to temperature impacts on demand.

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